

Electricity Network Charging in the Presence of Distributed Energy Resources: Principles, Problems and Solutions

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ABSTRACT

This paper discusses the principles of electricity network charging in the light of increasing amounts of distributed generation and the potential for significant increases in electric vehicles or distributed electrical energy storage. We outline cost reflective pricing, traditional public service pricing, platform market pricing and customer-focused business model pricing. We focus on the particular problem of how to recover network fixed costs and a recent example from Australia. We conclude that there are serious issues for regulators to address, but that potential solutions at the distribution level may already exist at the transmission level.

Keywords: network charging methodology, distribution charges, distributed energy resources, regulation

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✎ 1. INTRODUCTION ✎

In any network industry—e.g., communications, transport, electricity, gas, and water—there is a fundamental issue of how to recover the network fixed costs (or generalized system costs) from large numbers of users who put very different demands on the system and who have differing willingness to pay. While theory can provide some guidance as to efficient, profitable and fair ways to charge for network services—different objectives for charging often conflict. For instance, time and space varying charges for network use according to network condition might be efficient, but they are very unlikely to be fair towards poor inflexible network users, unable to respond to the signals they send.

Such conflicts are a problem because network industry regulators primarily exist to deliver BOTH *average* prices AND *price structures* (arising from charging methodologies which apportion overall costs to different classes of customer) which are socially acceptable at any given time as well as through time. Society often tolerates ‘unfair’ average prices and price structures when industries deliver higher quality services or generally falling prices (as might be the case in many communications markets at present). Where industry dynamism is low, unfair price structures without a clear rationale are unlikely to persist for long in heavily regulated industries. Where particular charging methodologies have developed over long periods that deliver

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(or are perceived to deliver) reasonably fair outcomes, these may come under pressure to be changed if they cease to deliver as previously.

This paper explores the network charging principles for the electricity distribution network in the light of actual and potential significant changes in the share of rooftop solar PV, electric vehicles and distributed electricity storage (so-called, distributed energy resources or DERs). These technologies, combined with smart metering which allows 2-way communication between the system and individual users about supply and demand in near real time, may put existing charging methodologies under extreme pressure.

A distribution network delivers transportation capacity. It is sized for peak system use, and there are some costs (e.g., for voltage support, frequency regulation, congestion-related energy losses) which vary in time and by location. Such capacity ensures that kWhs of energy and peak KW power can be delivered to customers at adequate power quality (e.g., within given frequency and voltage bounds). As a basic starting position, perhaps 80%+ of distribution network costs—if we attribute energy losses to retailers—are fixed in the medium-run for a given set of connections. In addition, DERs can offer flexibility (or reduced inflexibility) to the system in the presence of a general rise in intermittent, low inertia, generators.¹ Such flexibility services might include ancillary services to support renewable generation, or the reduction/increase of local demand to help match supply and demand in conditions of network congestion. Flexibility reduces the requirement for conventional network investments in core network assets such as lines and transformers.

Electricity network charges can be charged on both generation and demand and can be a combination of maximum rated capacity fixed charges, peak system injection/withdrawal and kWh usage. At the transmission level, network charges can be recovered on the basis of a combination of all three of these charges and payments by users of the transmission network (notably, retailers) *can reflect* time of use and locational elements. However, in most jurisdictions, smaller commercial and almost all residential users have traditionally faced a combination of demand based charges for distribution which include a small fixed element (typically 20% or less of total network charges)² plus per kWh usage (80% or more at average consumption). These charges have not varied by time or location within a given distribution network.

The rise of DERs means that the currently unsophisticated charging methodologies for distribution are being reconsidered as they may no longer be fit for purpose. The solution might be to consider extending pricing methodologies which exist at the transmission network level to the distribution level (such as system peak MW based usage charges or fixed per MW capacity connection charges), as distribution networks increasingly behave like transmission networks. However, even this is not an obvious solution, as transmission network pricing methodologies also vary substantially in their sophistication across the world.

The paper proceeds as follows. In section 2, we discuss four different sets of network charging principles, in the quest for theoretical guidance on network charging methodologies. Section 3, outlines the nature of problems posed for current charging methodologies by the actual and potential development of DERs in distribution networks. Section 4 then considers the nature of potential solutions to these problems and how regulators should approach evaluation of the need for changing current charging methodologies. Section 5 offers some conclusions.

1. See Strbac et al. (2016).

2. European Commission (2015, p. 114).

2. FOUR DIFFERENT SETS OF NETWORK CHARGING PRINCIPLES

In this section, we outline, compare and attempt to synthesize four different charging principles. Each represents a particular way of thinking about how to charge for network services in a world characterized by the need to price flexibility services in such a way as to deliver the electricity services that customers actually want, subject to high-level policy objectives on decarbonization, renewables and demand reduction. Different objectives on decarbonization, renewables and demand reduction can be incentivized directly, but clearly, the distribution pricing methodology may of itself influence them via their impact on the marginal price of using a kWh.

The four basic principles are: cost reflective charging, traditional public service pricing, platform market pricing and customer focused business model pricing. The first two have historically been closely associated with each other; similarly, there is a close relationship between the modern theory of platform market pricing and customer focussed business model pricing.

2.1 Cost reflective pricing

Cost reflective pricing recognizes that electricity network costs vary by time, location and power quality. In theory, network charges should reflect the cost of delivering of import and export capacity to network users. The cost of this capacity should vary by time of day, location and quality and by the amount of capacity itself (and whether it is export or import). For large energy users and large generators connected to the transmission system this is significantly the case already. Indeed, in many organized markets in the US, transmission system, users are exposed to locational marginal prices for power (reflecting short run congestion costs).³ By contrast, Great Britain transmission system users are exposed to zonal long-run marginal network expansion costs via zonal varying per MW connection charges. In the past actual network prices paid have not varied much by time of day, location or quality for most network users, significantly because of a lack of half-hourly metering. Yet, retailers have explicitly offered a large degree of averaging and wholesale price risk insurance to most final customers. However, as we noted above DERs (such as distributed storage) can respond to short and longer run price signals that more cost-reflective charging would send, because of the presence of smart equipment which can respond to real-time signals. This is especially important with respect to flexibility services, which have traditionally been bundled up with the monopoly distribution service, but could be made competitive (e.g., voltage support in the distribution network).⁴

A fundamental issue in cost-reflectivity is whether some of the traditional differences in the basis of network charging—e.g., for low/high voltage distribution level connected generation vs. transmission level connected generation—are fit for purpose given the direct competition between the services provided by these types of network user. For instance, transmission connected generators in Great Britain are required to pay a per MWh balancing services use of system charge (BSUoS), which is not paid for by distributed generation (DG), while there is no volume related export charge for micro-generators (such as household PV) connected at the distribution level.

Cost reflectivity, as represented by marginal costs, is not enough to ensure recovery of full economic costs for a network (see Perez-Arriaga et al. 1995). There remain unallocated

3. See Bohn et al. (1988) and Hogan (1992, 2018).

4. See discussion of the potentially competitive elements of current distribution service in CEER (2014, especially page 43) and in State of New York Department of Public Service (2014, especially page 20).

fixed costs that can be apportioned in a multiplicity of ways to individual consumers, most obviously by putting higher charges on richer consumers (a form of Ramsey-Boiteux pricing)⁵. This has little efficiency impact (for the electricity system) if the reapportionment does not affect consumption. Thus it would be possible to apportion the recovery of fixed costs through charges by income, property value, kW connection capacity or another indicator of income (or ability to pay), which did not result in distortion of the use of electricity.⁶ Of course in the past the easiest proxy for income, available to utilities, has been electricity usage itself and hence recovering some fixed costs via kWh charges has been favored (indeed via rising block tariffs in developing countries).⁷ High fixed charges can be distortionary if they result in disconnections from the network (or non-connection in the first place), while high variable charges can distort consumption downwards. In the past, the utility of electricity service has been so high (and the usage charges so low) that it clearly has not resulted in much disconnection (connection rates are close to 100%) or in much moderation of use among high-income consumers (price elasticities of demand are low).

2.2 Traditional public service pricing

Traditional public service pricing has sought to reconcile cost reflectivity and fairness⁸, while recognizing that networks often have public goods characteristics, such as the fact that some dimensions of power quality are common (e.g., system frequency stability). Regulated industries, such as electricity, are regulated precisely because of legitimate public interest in both the average level of and the distribution of charging between customers. Regulators are also tasked with enforcing socially acceptable levels of price discrimination.⁹ Regulated industries have been built up over decades and financed by past customer contributions; the current generation is paying for/benefiting from past network expenditure. Financial commitments entered into previously need to be honored by the current generation of customers. Perhaps 80% (or more) of current network financial costs are fixed¹⁰ and recovering these costs through network charges is a form of taxation. While some operating costs could be reduced if connections were to fall or planning standards (related to network resilience) were to be relaxed, they could probably not be reduced on less than a five to ten year horizon. In spite of this the overall fixed charge has been low for many customers.¹¹

Added to this, some network costs are related to the recovery of government imposed energy policy schemes, bad debt recovery costs and cover price insurance costs. Regulators have

5. See Ramsey (1927) and Boiteux (1971). Ramsey-Boiteux (or, simply, Ramsey pricing) pricing in the presence of higher social welfare weights on poor customers implies a modified form of the inverse price elasticity rule of fixed cost recovery (i.e. higher mark ups for fixed costs on more inelastic customers), which adjusts for the welfare weights. In the past rich electricity customers have also been price inelastic so that Ramsey pricing implies that they should pay much more towards the fixed costs than poorer customers. However in the future if rich customers with DERs become more price elastic this would imply that they should make less of a fixed cost contribution, than would have been optimal before.

6. See Boley and Fowler (1977) for a discussion of the traditional basis for charging in Great Britain.

7. A survey of 16 EU countries showed that 13 recovered more than half of their residential distribution charges via kWh related charges. (see European Commission 2015, p.114).

8. This reflects the Bonbright (1961) principles of utility rate making. Bonbright discusses in great detail the difficulties of implementing marginal cost based prices in practice—in the context of US utility regulation—in the presence of fixed costs and the need to recover them in a way that is socially acceptable.

9. See Stigler and Friedland (1962).

10. Simshauser (2014) suggests that distribution network costs are 60% sunk, 20% fixed and 20% variable in Australia.

11. See Cluzel and Standen (2013) and Ofgem (2015).

to approve both the level of prices and the charging methodologies¹² by which average price or average revenue caps are achieved. Charging very different prices to different households or small and medium-sized enterprises (SMEs) in the same area has not been an acceptable form of price discrimination, historically. However, some forms of cost reflectivity have been recognized as being important such as time of day pricing for larger users, charging customers in different areas differently, cost-reflective connection charges or charging more to customers connected at higher voltages. Going forward, the public service pricing principle may be thought of as giving rise to a form of grandfathered rights of access to the network on a particular charging basis. Careful thought should, therefore, be given to arbitrary reallocation of existing network access rights, via significant changes to the basis of network charges and the impact of new users of the network on the existing allocation of payments for network services.

2.3 Platform market pricing

Platform market pricing is about how to price the services provided in a two-sided market¹³. The classic example is the credit card company (e.g., MasterCard or Visa) that provides transaction services to retailers and final credit card users. Normally credit card users are given the cards for free, while the retailers pay transaction related fees, which they can pass on in higher goods prices to the users. MasterCard for example, as the platform provider for their global payments system, coordinate both sides of the market and there exist powerful network externalities, implying that the utility of users of a platform depends on the number of other users—either on the same side or the other side of the platform. ICT and the associated complementary innovation are essential components of platform markets: this creates added-value that increases utility to all user groups. The electricity distribution network operator can be thought of as a platform provider, providing services to both final electricity consumers, conventional generators and to flexibility providers who own DERs. In the future we can imagine energy service companies (ESCOs) placing DER equipment on their customers' premises for free¹⁴, paying the network companies and recovering the costs from the customers in higher energy service charges. Distribution Network Operators (DNOs), acting as the platform owner, might want to encourage this by rebalancing their charges away from households and focusing them on ESCOs. The State of New York has explicitly adopted the idea of the distribution utility as a distribution system platform provider (or DSP) for the promotion of DERs.¹⁵ The platform idea should focus consideration of what is the unique service provided by the regulated network and what are the services that are sold across the platform between the two sides of the market. At a basic level, a transparent and simple platform user charge could serve to promote the use of the platform (e.g., by flexibility providers) and more importantly increased overall trading value (as in the credit card example), in a way that finely tuned cost reflective pricing may fail to do.

2.4 Customer focussed business model pricing

Customer focussed business model pricing puts customers and what they value at the center of charging principles (rather than narrowly focusing on optimality in pricing, which is still

12. In Great Britain these are the Common Distribution Charging Methodology (CDCM) and EHV Distribution Charging Methodology (EDCM).

13. See Weiller and Pollitt (2013).

14. For instance, Richter and Pollitt (2016) find that household electricity customers would expect the ESCO to pay them for locating DERs on their premises.

15. See State of New York Department of Public Service (2014), Pollitt and Anaya (2016) and Jones et al. (2016).

the case with platform market pricing). Business model theory focuses on value proposition, value creation, and value capture.¹⁶ Customers are willing to pay for something when it satisfies a need for them (i.e., it has a *value proposition*). A given good or service must involve *value creation* for the customer, by effectively satisfying this need. Finally, there must be some way for service providers to monetize these customer benefits (*value capture*). The key issues for DERs are: do they have a value proposition for ultimate customers; what services do they actually provide to the system; and how can they be remunerated effectively. There is more than one way for a given DER to be remunerated. Gassmann et al. (2014) identify 55 generic business models (e.g., pay per use, subscription, revenue sharing, etc.). In modern markets (e.g., the platform markets mentioned above) with large numbers of service providers and business-to-business (B-to-B) transactions, the allocation of value to individual businesses is complex. It is often achieved by exploiting multiple revenue streams. It should be remembered that manipulating network charges to send price signals to DERs is only one of several sources of cost and benefit for DER investors and it may not be decisive or indeed effective¹⁷. It is also the case that distribution network operators (DNOs) and transmission companies should also be incentivized to innovate uses for their platform and are in a good position to respond to potential future uses of their own networks, subject to a requirement not to disadvantage their current customers.

2.5 Discussion

These four different approaches to network charge determination all recognize the importance of a degree of cost reflectivity in the charging methodology. However they put very different degrees of emphasis on this as a charging principle. This is a separate issue from the determination of the overall level of charges (i.e., total regulated revenue) that has to be set by the regulator as part of the price control review process / 'rate' setting process. Normally charging methodologies are simply approved by the regulator and display a high degree of inertia over time. These approaches also draw attention to where fixed cost recovery should be focused and on the need fair charging and to the promotion of innovation and increased use of networks that have public good characteristics and exhibit network externalities.

It is also important to be clear that in the end it is very difficult to avoid the distortion created by the difference between consumer and producer prices. This is common to all goods in society. Consumer prices include taxes (VAT, recovery levies, fixed costs), producer prices do not include these. There is always going to be a 'tax' advantage in self-supply. This will tend to undermine the ability to recover fixed costs in conditions where end users are allowed to make investments in their own distributed energy resources. The question is how serious this distortion will become and whether moving the recovery of electricity taxes to other elements of electricity service, other than kWhs, will be possible.

Another possibility is to extend the current charging basis to include own-use of DERs (such as storage and PV).¹⁸ Currently, this is straightforward because much own production at the household level commands a subsidy payment and hence must be metered and reported. However, as PV prices fall and requirements for registration and metering of all production are

16. See Teece (2010) and Oseni and Pollitt (2017).

17. See Northern Powergrid (2015).

18. Developments in digital rights management have shown that this is possible in other sectors. We have now developed the technology to charge for every view of a page or a TV programme, regardless of whether it occurs using customer owned equipment. This has undermined the ability of owners of copies to trade them free of 'tax' (as is the case with books or CDs).

no longer necessary to receive a subsidy payment, in the future this sort of arrangement may raise privacy issues / not be enforceable.

This paper focuses on the charging models for network companies. However final charges for electricity service are determined by retail companies, not network owners, these are the prices that most customers see and respond to. We should be clear that it is up to retailers as to the extent to which they wish to pass through the variations in network charges they incur to their retail customers.¹⁹ A recent survey found that this was even true for half-hourly metered industrial and commercial customers in Great Britain, very few of whom were actually exposed to any of the underlying variation in their network charges.²⁰ Thus sharpening underlying network pricing signals may not make much difference to what final users do because of the limited degree of price pass-through to final retail prices. While regulators can seek to regulate the pass-through of charges, this would be to ignore the value that all retail customers, including business customers, place on simple to understand pricing structures and value of common national or regional prices to retailers.

Some authors (e.g., Biggar and Reeves 2016) have emphasized that underlying network charges should reflect all substantial variations in costs—which can be identified externally—while at the same time being offered with hedging products. However, this is not common practice in most markets, where often only substantially hedged products are offered to final customers, and ‘basic’ unhedged prices may not even be quoted. This is because the offering of sophisticated choices between hedged and unhedged products is expensive. Even potentially sophisticated purchasers of network services have to consider their ability to manage underlying input risk and have limited ability to pass on input price fluctuations to their own customers. Hence there is a generalized preference throughout the economy for pricing which is easy to justify and advertise.

✎ 3. THE PROBLEMS POSE FOR EXISTING DISTRIBUTION CHARGING METHODOLOGIES ✎

Now we consider a case study of how network charging regimes can rapidly become unfit for purpose in the presence of a big uptake of particular DERs.

South Queensland in Australia has one of the highest penetration rates of domestic solar PV in the world. 22% of households had PV in 2014 (and 75% have air-conditioning).²¹ *Distribution charges in South Queensland* are charged on the basis of 20% fixed cost and 80% per kWh. The massive increase in solar PV (from close to zero at the start of 2009) has resulted in a huge transfer of wealth and costs between customer groups. Solar PV consumers have lower metered consumption due to own production. This significantly reduces their share of the per kWh costs of the distribution system. Meanwhile, the revenue cap regulation of the distribution charges means that the same revenue has been recovered as the number of units has fallen, thus per unit charges have risen and the distribution of their payment between different types of households has dramatically changed.

19. A check of available retail offers on one price comparison site for my property on 14 March 2016 revealed that annual standing charges for electricity ranged from £61.90 to £100.01.

20. Northern Powergrid (2015, pp.48–50).

21. See Simshauser (2014), for another Australian perspective on the issue of PV uptake see MacGill and Smith (2017) and Mountain and Carstairs (2018).

TABLE 1
Differences in Network Charges for Residential Consumers in South Queensland
(in Australian dollars)

	Household A No air-con No Solar PV	Household B Air-con No Solar PV	Household C No air-con Solar PV	Household D Air-con Solar PV
Maximum Demand (kW)	1.41	2.14	1.40	2.09
Metered Import (kWh)	6253.4	7560.6	3820.1	4707.1
Solar Export (kWh)	0	0	2259.1	1838.8
Gross Demand (kWh)	6253.4	7560.6	6253.4	7560.6
Number of Customers	283849	694643	26151	235357
% of Customers	23%	56%	2%	19%
Base Network Tariff	\$1006.14	\$1171.37	\$698.57	\$810.69
Differences	A-C \$307.57	B-D \$360.68		

Source: Simshauser (2014).

Simshauser (2014) analyses four types of household in this new situation: households with no PV and no air-conditioning (this is the poorest group); households with air-conditioning and no PV; households with PV and no air-conditioning; and households with PV and air-conditioning. He looks at how the charging mechanism has shifted the payments and considers a more cost reflective charging regime where each household pays a fixed charge, a per kW peak charge and a variable per kWh charge which better reflects underlying costs. What he finds is that households with PV and air-conditioning have only a fractionally lower peak per kW usage relative to those with no PV but air-conditioning. Meanwhile, households with air-conditioning and no PV currently pay less than they should towards distribution charges, given their relative cost of service. The impact is striking. The poorest group without PV and air-conditioning currently pay 307 Australian dollars p.a. more (or c.\$235²², i.e., around 40% more) than those with PV and no air-conditioning (see Table 1). This reveals that the starting point of charging is already unfairly subsidizing peaky users with air-conditioning AND that the system has rapidly become much *more* unfair with the high take-up of PV. A more cost reflective three-part tariff schemes sees those with PV and air-conditioning paying 28% more than at the moment and those without both paying 15% less (with the result that the poorer households pay around 180 AUD (\$137) less). Simply put: the relationship between kWhs and kW peak observed prior to the arrival of PV has fundamentally changed, such that kWhs are a poor proxy for kW peak demand.

The above example from Australia makes a point, but it is extreme, if not unique²³. It arises from a combination of high underlying network charges, high PV penetration, and high solar radiation. In a different jurisdiction, there could be a lot less impact from the same DERs. Thus, in the UK underlying electricity distribution network charges average around \$130 (or 1/6 of the level in South Queensland); household PV penetration has reached a maximum of around 5% in the sunniest regions (1/4 of Queensland); and typical residential PV output and

22. 1.31 AUD = \$1 as of 3 November 2017.

23. Jones et al. (2016) also discuss the case of Hawaii, which has very high penetration of domestic PV.

export is 1/2 the Queensland level. This suggests a bill impact of around 1/48 of the Australian level, or just a few pounds (and less than 1% of the total bill). This is likely to be common to many temperate regions. Indeed, Athawale and Felder (2016) showed that for New Jersey the impact in 2014 of net metering was only around \$1 per month for the poorest households. These observations immediately suggest that some jurisdictions will be under more pressure to change their distribution charging methodology than others from certain types of DERs.²⁴ The so-called utility death spiral²⁵ is currently unlikely in most places²⁶ but may be an issue in some, significant, parts of some networks.

Differences between in the basis of charging itself at different voltage levels may distort the choice of where to connect DERs.²⁷ The nature of the charging methodology may influence the choice between storage, generation and load and the nature of integration between the three. In principle, it is desirable that the charging methodology and in particular the 'tax' component of use of system charges should not distort the location and type of investment on the network. In practice that might be very difficult to achieve via any given charging methodology.

Related to the above point, one can overemphasize the impact of the existing charging methodology at the 'grid edge' (see Sioshansi 2017) or the likely significance of a shift in electricity asset ownership (see Smith and MacGill 2017). If some households do substantially invest in DERs in remote locations and make much less (even zero) contribution to grid costs, it is not altogether clear that this necessitates a generalized change in the charging methodology. The grid-edge (which is where a lot of small-scale DERs might be located) is already heavily subsidized within the existing electricity system where non-location varying tariffs favor remote connections. What matters in the long-run is the cost contributions of a large majority of grid-users for whom extreme DER options (such as complete grid-disconnections) are not currently a viable option.

Some of the issues raised by DERs would seem to be solved by introducing transmission network type charging methodologies in the distribution system. The Queensland problem might have been solved by export charges for kWhs or moving to kW peak demand charges. This would have largely protected the non-PV households from the negative impact of the uptake of PV, while actually being more cost reflective. However, many jurisdictions do not charge generators for the use of the grid (no export charges), and there is wide variation in the total amount of transmission charges recovered in kW peak demand charges (as opposed to kWhs demanded). So, simple extension of current transmission charging methodologies to distribution may not be a solution because they are not themselves optimal at the transmission level. Hence, while some (e.g., Knieps 2016) have argued for the extension of nodal pricing to the distribution level as the solution to the rise of DERs, this argument has not been won at the transmission level in many (indeed most) jurisdictions. Transmission charges themselves still have to recover fixed costs and nodal pricing does not in of itself solve the fixed cost recovery problem illustrated by Queensland.

24. See analysis of drivers of residential solar PV uptake across the US in Kwan (2012).

25. See Sioshansi (2016, xxxi ff.) and Athawale and Felder (2016).

26. See Gellings (2016) on why the current charging models are still fit for purpose.

27. For instance, the nature of DUoS charges for DG connected to the extra high voltage distribution network (under the EDCM) vs DUoS charges for DG connected at lower voltages (under the CDCM) is different in GB and may distort the decision of which voltage to connect at.

A more fundamental problem is the fact that changing the charging basis may only really allow core network costs to become more optimal in the long run (often very long run) as the network is optimally reconfigured over time. Many networks in developed countries are oversized for current demands, and hence the scope for actually reducing costs in the medium run is limited, and the economic benefits of reduced network use are small. The longtime horizon for network cost reductions is a problem for DER investments which need to see price signals in the much shorter run (due to their higher discount rates and shorter time horizons) than the 40–70 years which it may take to reduce the need for conventional network investment.

DERs which impact network costs can easily be over-rewarded for any network cost reductions. One reason for this is because small discrete contributions to the provision of network services should properly value their failure to deliver risk. Conventional networks may have 99.99% (one hour per year of lost load) or more availability²⁸, whereas individual asset availability may struggle to reach 98% availability. Thus, a household that is rewarded for the presence of a distributed storage device which reduces its average peak consumption, but where the device does not deliver on some days of the year, is over-rewarded. The risk is that DERs paid to provide network services (to facilitate network capacity or quality) in an uncoordinated way will be collectively more expensive (and/or more risky) than conventional coordinated distribution company provided solutions, i.e., systemic failure to deliver risk from DERs will not be priced properly.

Regulators could also be faced with a stranded asset problem in conventional distribution network solutions. DERs might mean that substantial or discrete parts of the existing network could be written off / written down in value. The question is how and when to do this? This has been done before when liberalization gave rise to the accelerated depreciation of generation assets forced to close early and competitive transition charges to pay for generation asset write-downs. One could argue that the regulated equity risk premium enjoyed by distribution assets incorporates some probability of a substantial asset writes down at some date. Even a very low 2% equity risk premium suggests equity will be written off every 50 years!

How retailers expose final customers to any changes in the distribution charging methodology remains to be seen. This means that while regulators may seek to change the basis of regulated distribution charges, they may not ultimately have much impact on the realized charges to which poorer households unable to respond to DER incentives are exposed unless they are prepared to extend regulation of retail tariffs.

✎ 4. SOLUTIONS TO THE IMPACT OF DERS ON THE DISTRIBUTION ✎ CHARGING METHODOLOGY

When looking for solutions to the problems posed by the widespread uptake DERs on the existing charging methodology, there are a number of issues to be considered which are worth emphasizing.

To begin with, the mix of fixed KW capacity, kW peak use, kWhs exported/imported is not obvious. While we have seen a lot of concern in some jurisdictions about the uptake of PV in the context of kWh based network charging, a similar uptake of electric vehicles might have the opposite effect. Widespread uptake of electric vehicles, principally charged at home,

28. In Great Britain all the distribution networks have less than 60 minutes per year of interruption. See <https://www.ofgem.gov.uk/data-portal/customer-interruptions-and-minutes-lost-electricity-distribution-riio-ed1> (Accessed 3rd November 2017).

would increase the contribution of rich households to total network costs. Similarly, a switch to electric heating, using air source heat pumps, would also potentially reduce current electricity charges for users who do not install them. Fixed kW capacity based charging may be cost-reflective, but it will unwind the conventional quantity based discounts enjoyed by low users (particularly single person elderly households).

Outturn political acceptability of network charging methodology remains important for economic regulators. A point worth bearing in mind is that the cost to the consumer of the network reducing the reliability of electricity supply from its current level of 99.99% to 98% (self-supply) is very high. For the UK, loss of 2% of 3.2 MWh—average annual household electricity consumption—at a value of a lost load of £10,000 per MWh²⁹ on a willingness to accept basis, implies the need for a compensation of £640 to give up current levels of reliability. This suggests that the underlying economics of any reduction in network reliability from its current level contingent on the value of DERs is challenging. In addition to this, Green and Staffell (1917) show that it remains highly unlikely that domestic storage will be cheap enough to make disconnection an economically viable option for most household consumers in the UK, even by 2030.

Some charging solutions can be adopted in an evolutionary fashion as issues and opportunities arise. The desire to increase or reduce demand in parts of the network at certain times in order to minimize system costs does not require all users to be exposed to time and space varying network charges. It only requires the existence of markets for flexibility or regulatory requirements to sign DER flexibility contracts (as a form of ancillary services). Thus, whatever the basis for published ('posted') network charges is, what matters is whether efficient deviations from those prices can be offered to DERs and other providers of flexibility to the network. Such discounts to posted prices can be selectively offered to flexibility providers who actually deliver services that are contractually useful to the network rather than incorporated into the posted prices directly.

New devices offer opportunities for new charging bases related to those devices. Thus, domestic PV export, fast EV charging and distributed ancillary services provision offer new opportunities for the introduction of cost-reflective charging related to the new uses of the network. Just as developments in telecommunications technology have seen reduced time and space differentiation of conventional voice telephony, they have also seen a proliferation of charges for new products (e.g., texts, different speeds of broadband access, etc.). New products are opportunities for recovering a share of network fixed costs from new uses of the network.

It is worth reiterating a general point, that cross-subsidies from the network charges to other parts of the electricity value chain should be avoided or at the very least made explicit. It is clearly wrong to use network charges to collect or deliver subsidies to solar when customers are increasingly able to respond, in ways that are both inefficient and unfair, to the miss-incentives that are thus created. While PV penetration was low, this might not be a big issue in some jurisdictions, but it has clearly the potential to become significantly distortionary. As a follow-up to the Queensland case, the Australian national regulator (AEMC) has now published a rule (November 2014) that there should be a presumption that DERs should be connected but that 'network charges should be cost-reflective for all network users'. It has introduced a 'tariff structure statement' for networks which should explain how a given networks' charges comply with the objective. There has also been a move towards legal separation of DNSP (distribution

29. See London Economics (2013, p.31).

network service provider) and attempt to make non-monopoly services of DNSP contestable. Both the regulator and the industry have consulted on future developments.³⁰

Given that DERs can make a case for being compensated to the value of the best alternative solution it is not clear that the ultimate consumers will see any expected benefit (just increased cost risk) unless there is a net benefit test, i.e., DERs should pay a system fixed cost contribution out of any savings that they generate to compensate the other contributors to the system for their underwriting of their costs. This should be in addition to any benefit that might derive from the competitive provision of DERs, such that winning DERs can be paid less than the system value of their services. It also clear that DNOs should not be allowed to mop all of the remaining cost savings arising from DERs provided that do not accrue to the DER owners, e.g., in Great Britain via regulatory incentive payments under the current network price control methodology, RIIO. Thus, the interaction between the regulatory encouragement to save conventional system costs, to promote innovation and to satisfy the desires of DER stakeholders should not give rise to higher payments for existing final customers whose behavior does not change.

There is a need to recognize that getting the regulation of network charges right does not ensure that they will be reflected in retail tariffs and some interventions seem likely to prevent retail tariffs which exploit behavioral traits of consumers—such as customer inertia, vulnerability or lack of cognitive capacity. Indeed, regulators seem likely to want to continue to impose tariffs where poorer customers ARE actively cross-subsidized by rich ones as currently happens with low user tariffs.

Finally, it is worth saying that it should not be up to the regulator to ‘design’ optimal tariffs or to necessarily find a way to make new DER business models viable. Rather it is up to new energy service providers using DERs to prove that they are providing aggregate system benefits and hence negotiate reasonable distribution tariffs with distribution entities and/or propose reasonable tariffs to the regulator.

✎ 5. CONCLUSIONS AND OVERVIEW OF REGULATORY OPTIONS ✎

We discussed some of the principles, problems, and solutions behind the impact of DERs on electricity distribution network charging. The principles of how to charge for electricity networks are complicated. We have discussed how there are several different models on which network charges could be based. The bottom line is that individually and collectively they do not offer clear guidance as to how best for a given regulator to set distribution network charges for households and other small users. This because of both fairness and non-obvious efficiency considerations.

Any charging methodology for an electricity network has to deal with the issue of fixed cost recovery. This is effectively a tax, which needs to be levied on network users. The tax rate on an individual network user could be higher or lower, but network fixed costs need to be recovered in aggregate, and this will lead to some clear incentives on heavily taxed users to make investments driven by tax avoidance advantages.

The tariff methodology problem (as opposed to the average price or return problem) is becoming more significant with the increasing emergence of DERs on the electricity system. This is a material issue in mature networks which are not growing and where the tariff methodology

30. See AEMC (2017) and CSIRO (2017).

could easily produce much larger annual fluctuations in individual customer costs than the average uplift in costs (due to total cost changes).

Solutions do exist in how to respond to DER uptake. These are likely to include some combination of export and/or import charges for network use (by kW or kWh), peak kW export and/or import capacity available, higher reconnection charges where disconnection is a genuine option and charges for new services such as fast charging or connection as an ancillary services provider. Modelling of the likely impact of PV, EVs and distributed electrical energy storage on who pays for the network under different charging methodologies will help the regulator anticipate what methodologies might make a difference and extent to which significant changes are necessary. In the short run, high uptake of PV in urban areas would suggest a move to either export use charges or kW peak use charges to prevent the Queensland situation emerging.

There will be lots of scope for learning from relevant experiences elsewhere. However, regulators will have to pay due attention to their own statutory duties with respect to efficiency, equity and the promotion of innovation and competition. Different regulators will likely place different emphasis on each of these, with very different implications for acceptable charging methodologies.

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